Testimony for
Subcommittee on Energy and Mineral Resources
Committee on Resources
U.S. House of Representatives
Oversight Hearing on
The Scientific Inventory of Oil and Gas Resources on Federal Lands

Submitted by
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Members of the Subcommittee, I am Dr. Michelle Michot Foss, Executive Director of the Institute for Energy, Law & Enterprise and an Assistant Research Professor at the University of Houston. I am also current president of the International Association for Energy Economics (and past president of the U.S. Association). I have worked on natural gas industry, policy, and regulatory issues for about 20 years. I come at the invitation of the Subcommittee to provide input on the current and future prospects for natural gas in the U.S. and to comment on various policy and other issues that affect, and are affected by, this important natural resource. I come as an individual citizen, professional, and expert, and do not represent the viewpoints of any particular organization or institution.

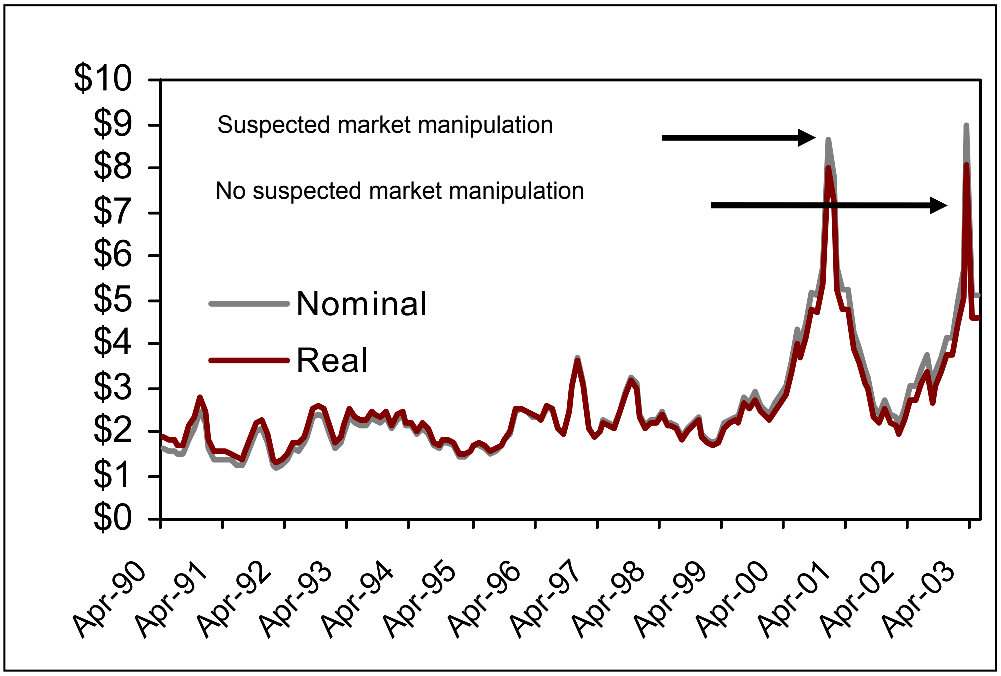
This Subcommittee and Hearing are concerned with the potential crisis stemming from the natural gas supply shortage which has brought about a doubling in the cost of natural gas in the last year alone. Focusing on domestic economic implications, from price fluctuations to national security, the hearing will analyze the factors that have restricted domestic natural gas production in a time when we need it most.

My testimony deals with several aspects of the situation for natural gas at the present time, as well prospects for the future and key policy considerations.

HISTORICAL PERSPECTIVE ON THE NATURAL GAS SUPPLY-DEMAND BALANCE

Natural gas supply, demand, and price today are a reflection of both past and present conditions in the industry and U.S. energy marketplace, as well as in the macro setting for natural gas – the U.S. economy and weather patterns (to which natural gas use is quite sensitive). **Figure 1** below illustrates that since April 1999, the U.S. has experienced two sharp price spikes for natural gas. The first occurred during a period of strong economic growth and turmoil in energy markets in the western states. (The spot price for natural gas, essentially the "near month" of the Henry Hub contract, does not incorporate basis differentials for other locations, such as the disputed California border.) The second price spike occurred this past winter of 2003, during a period of slow economic growth and relatively calm energy market conditions (notably, following the demise of many large energy trading operations), but also with harsh weather conditions that supported a more "normal" winter heating season. Comparison of these price spike events, *characterized by quite different conditions* with regard to demand factors (U.S. economic activity and weather patterns) suggests that natural gas market fundamentals may have shifted significantly relative to recent history.

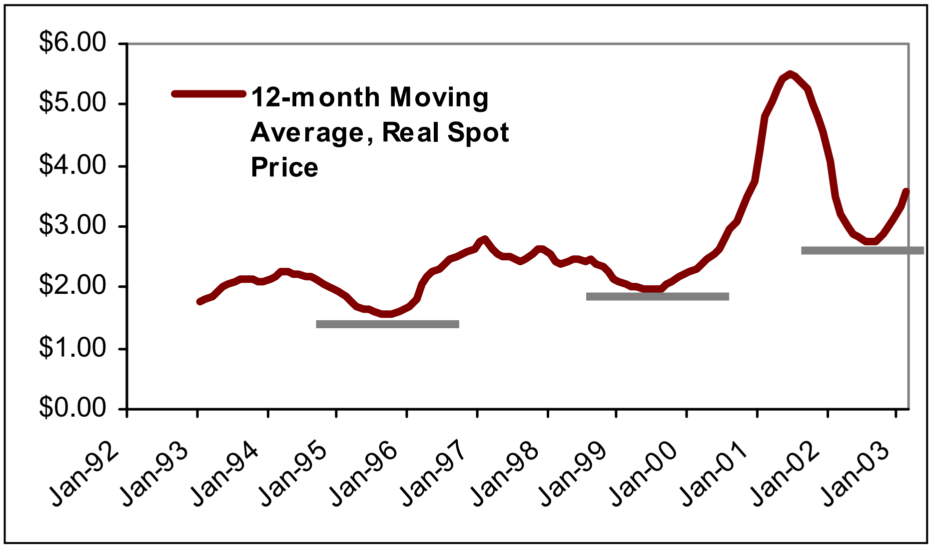
Figure 1. Natural Gas Spot Prices



Source: New York Mercantile Exchange (NYMEX)

The evidence for changing fundamentals is further supported if spot price data is smoothed using a 12-month moving average (MA), as shown in **Figure 2** below. Smoothed data indicate that the trough of each price cycle since 1992 has edged upward, most strongly during 2003. That is, *each price floor is higher than the floor of the preceding price cycle*. Thus, even during relatively quiet periods with respect to natural gas demand (outside of winter heating, summer peak electric power generation, and summer storage refill), natural gas prices have been on an upward trend.

Figure 2. Natural Gas Spot Prices, Smoothed

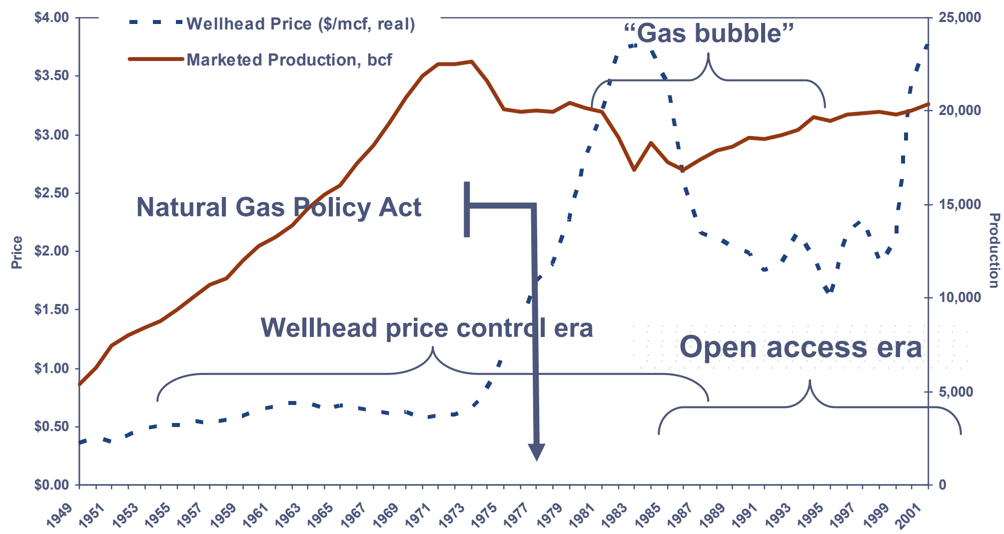


Source: NYMEX

Price data demonstrate that the U.S. is experiencing supply-demand tightness, and that this tightness could persist. Several factors are worth considering which both support a more bullish outlook on prices (from the producer perspective) but which also could dampen prices and contribute to surplus deliverability in the years ahead.

- *Current high prices might reflect a "re-bound" from the prolonged effect of the "gas bubble."* **Figure 3** below highlights some key historical events for the natural gas industry. The gas bubble (or "sausage" as it came to be called) was a major driver for consolidation in the exploration and production segment for both operating and service companies. Surplus deliverability and low prices discouraged investment. Drilling activity languished. Introduction of open access helped to reduce the surplus deliverability, as did the expansion of gas-fired electric power generation capacity (encouraged by low natural gas prices). However, it is worth considering two things.
  1. The rapid build up of production deliverability during the 1970s and the surge in wellhead prices as pent-up demand was expressed in the marketplace and wellhead decontrol unfolded *may have lulled the industry and customers into complacency with regard to availability of supplies and associated prices.*
  2. The problem of complacency may be especially true because business conditions while the bubble/sausage was in effect were terrible. During the slump in wellhead prices, the Gulf of Mexico became known as the "Dead Sea" as rigs were pulled out of service for use elsewhere. *It is quite likely that the constraints on natural gas supply today and through at least the mid-term are a result of inadequate investment upstream from the mid-1980s through the late 1990s.*

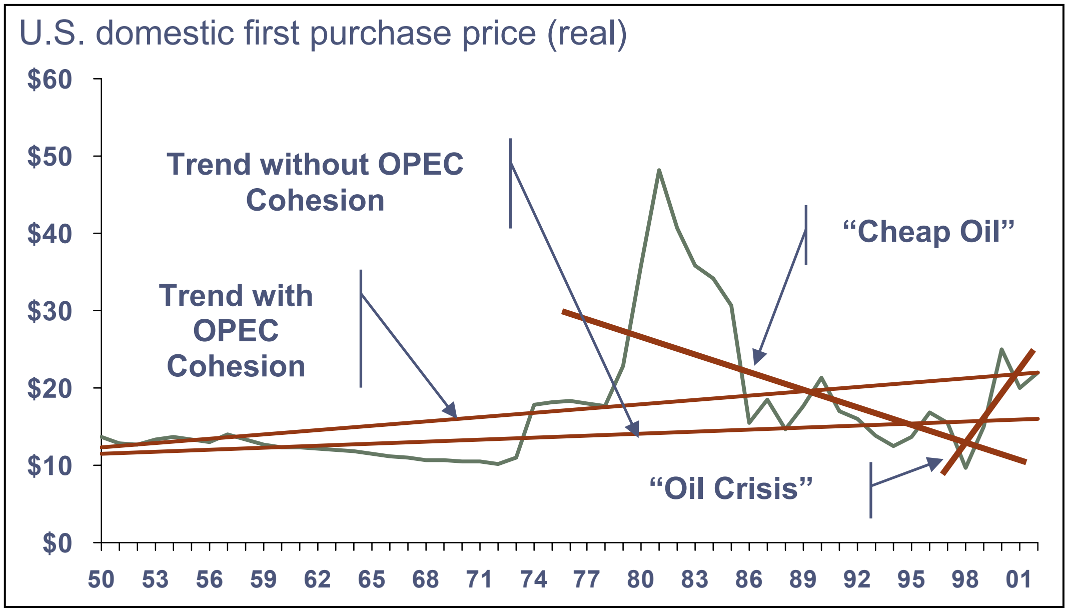
Figure 3. Long Term Wellhead Prices for Natural Gas and Production



Source: U.S. Energy Information Administration (U.S. EIA)

- *E&P for natural gas is driven not only by expectations for natural gas prices, but also by oil prices, because natural gas is often associated with crude oil and therefore produced simultaneously, and also because natural gas competes with oil at the "burnertip."* Many customers, such as industrial facilities and power generators, can switch between fuel oil and natural gas to take advantage of more favorable pricing on a Btu basis (British thermal unit, used to equate energy content of different fuels). Oil is a fungible, global commodity that has its own supply-demand interactions. The Organization of Petroleum Exporting Countries (OPEC) has a large impact on both current and expected future prices of oil, and therefore indirectly on natural gas prices in the U.S. As shown in **Figure 4** below, when OPEC decision making is cohesive (i.e., there is little disagreement among members), the long term oil price trend is slightly higher. Natural gas prices tend to be higher during periods of oil price firmness. OPEC decision making is opaque, adding an element of uncertainty to expected oil prices and thus impacting drilling decisions and, indirectly, natural gas production. In addition, there are two, strong, competing viewpoints with regard to oil prices that have great consequences for natural gas: are we in an era of "cheap oil" in which there is always sufficient supply, in response to demand and price signals, to mitigate upward pressure on prices? Or, are we in an "oil crisis" in which demand growth in regions like Asia, capacity constraints in the Persian Gulf petroleum "breadbasket," conflict and political risk in key oil producing regions (Middle East and West Africa for instance), and uncertainty about non-OPEC production capacity and potential all combine to keep oil prices high? *Both of these competing viewpoints bear important consequences for natural gas supply and pricing.* Finally, the collapse and prolonged slump in oil prices from the mid-1980s until the most recent high price cycle aggravated (indeed, caused) E&P industry consolidation and hindered investment.

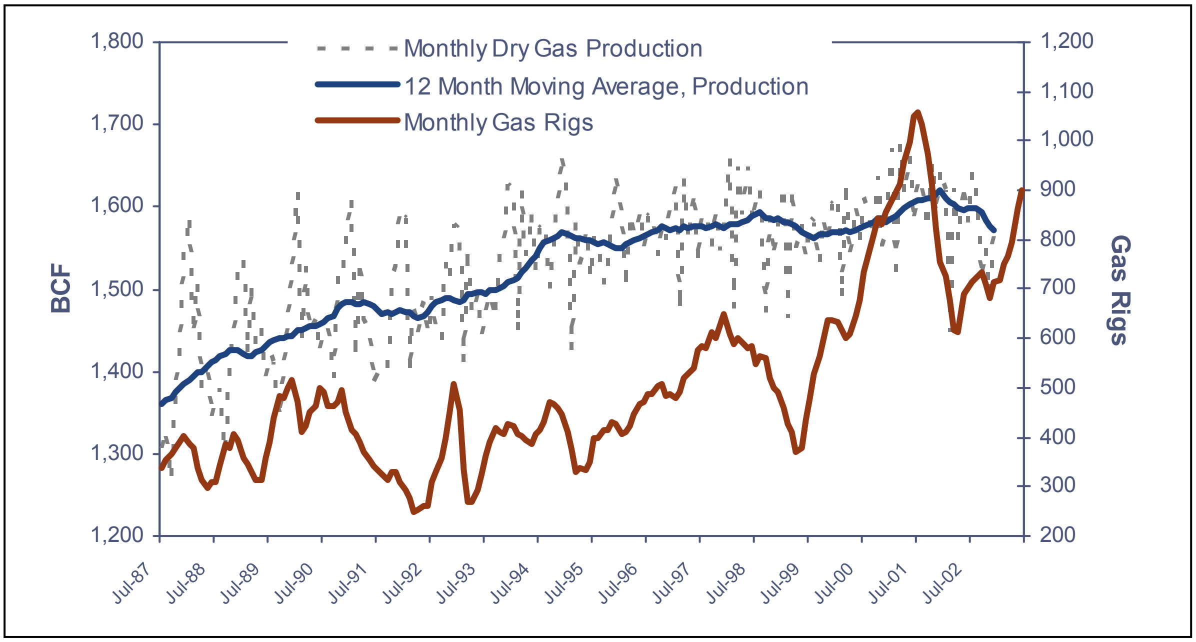
Figure 4. Long Term Oil Prices (Wellhead)



Source: U.S. EIA

- *The U.S. is experiencing both depletion and steep decline curves in established fields, and also lower rates of productivity in new gas wells.* **Figure 5** below shows the E&P industry challenge. Given the maturity of U.S. basins, it is essential that gas drilling be maintained at a sufficient level to ensure deliverability. A central question is whether new drilling will yield gas production at rates equivalent to historical patterns. Indications are that well productivity onshore may not reflect past rates of production. The industry is also on a well known "treadmill" in which new drilling and production barely offsets natural depletion and declines (especially true for "fast gas" reservoirs, such as the shallow water, continental shelf of the U.S. Gulf of Mexico). A mitigating factor is deep water production – as sustained production flows are established, deep water plays will make a more substantial contribution to the U.S. supply base. However, importantly, upwards of 75 percent of domestic production comes from onshore fields (see comments on U.S. Gulf of Mexico resources below). Onshore, critical components of the resource base include non-conventional reservoirs (coal seams and tight sands and shales) that present unique risks and costs.

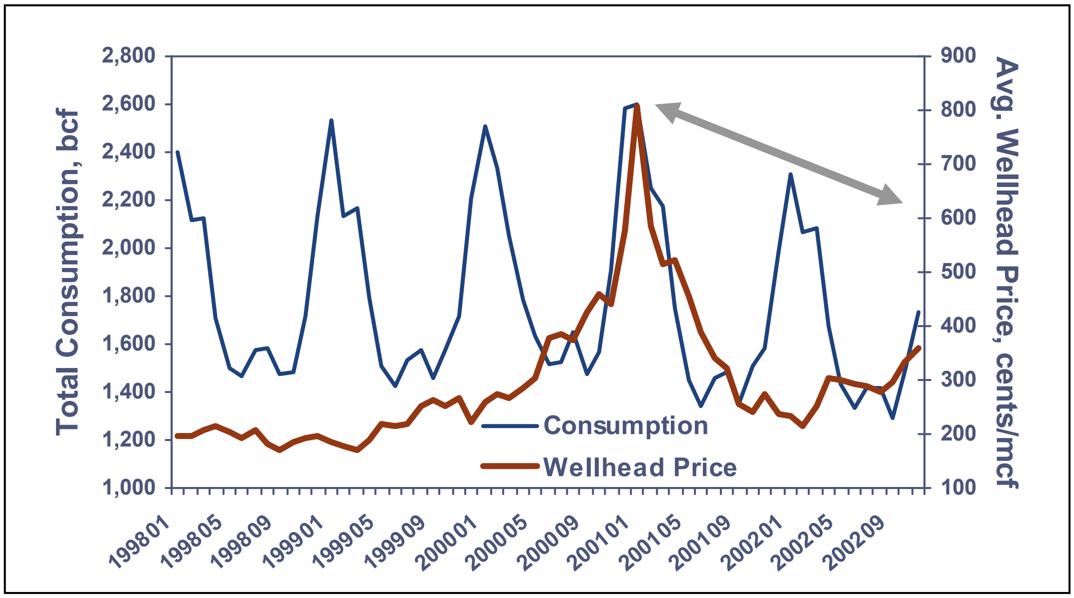
Figure 5. Natural Gas Resource Development



Sources: U.S. EIA and Baker Hughes

- *Offsetting tension on the supply side are adjustments on the demand side.* In any open, competitive market, consumers will adjust their demand for a good according to price (and their willingness to pay, subject to other factors like income, elasticity of demand, and so on). *This is a normal, logical reaction and one that suppliers must deal with.* To the extent that demand adjustments reflect more efficient use of a scarce resource like natural gas, we will be better off in the long run. Conservation and efficiency have important roles to play in the U.S. energy sector, and the best encouragement is via price signals. **Figure 6** below illustrates the process of demand adjustment that has been taking place since the winter 2000-2001 peak in natural gas consumption.

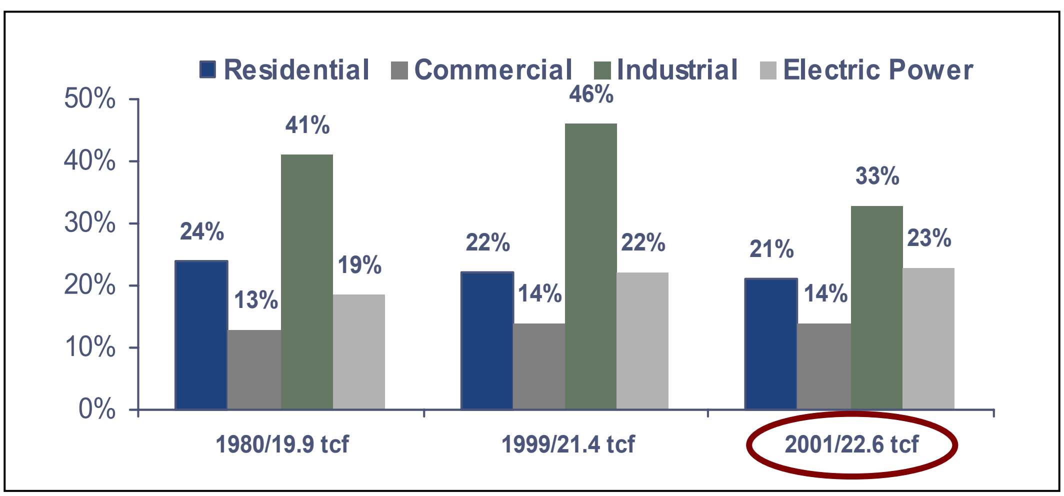
Figure 6. Demand Destruction for Natural Gas is Real



Source: U.S. EIA

- *However, a certain amount of demand loss represents lost economic activity and capacity for the nation.* It appears that most of the demand destruction taking place is in the industrial sector (**Figure 7** below). Natural gas serves as feedstock for petrochemical applications – from which come all of the essential materials we use in everyday life. Natural gas is also an important fuel for manufacturing and industries like steel are affected. Note that the most recent data available for natural gas consumption is 2001. Expectations are that 2002 data will indicate an even sharper decline in natural gas use for the industrial sector.

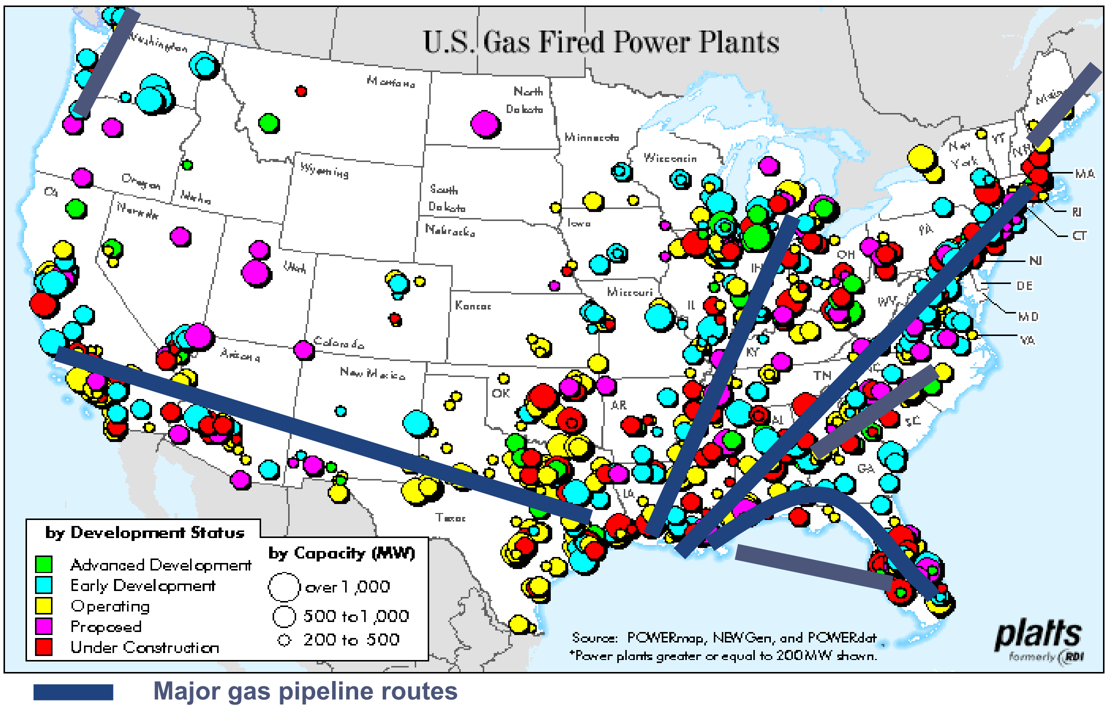
Figure 7. Natural Gas Consumption by Sector



Source: U.S. EIA

- *Natural gas use for electric power generation has increased dramatically since the 1980s.* This is a result of advances in natural gas turbine technologies as well as policy incentives through termination of prohibitions on natural gas use and creation of competitive wholesale markets for electric power (1993 Energy Policy Act). Projections of demand for electric power have been key to natural gas resource development. Most new gas-fired power generation is developed along major gas pipeline routes, as shown in **Figure 8** below.

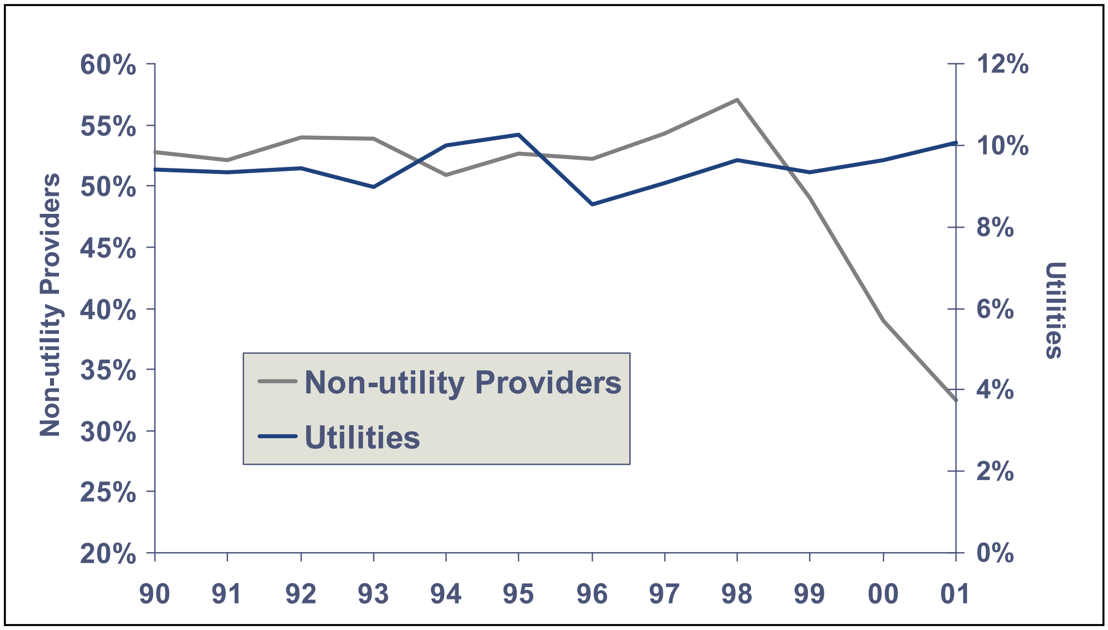
Figure 8. U.S. Gas Fired Power Plants and Major Pipeline Routes



Sources: Platts, UH IELE

- *The impact of higher natural gas prices on electric power generation is controversial.* Data on gas-fired power generation are not clear. At least one information source (**Figure 9** below) suggests a sharp impact on gas-fired generation in the higher price environment. An important consideration for policy decisions is quality, reliability, and timeliness of information on the electric power component of the natural gas value chain.

Figure 9. Natural Gas Generation as A Percent of Total Net Generation



Source: BP 2002 Statistical Review

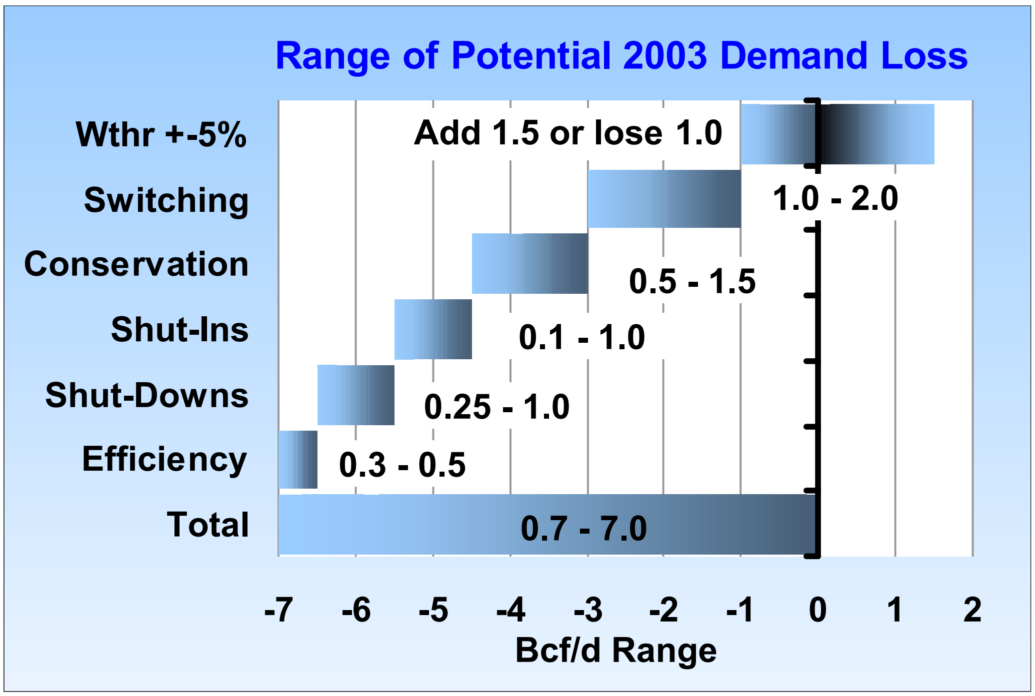
In summary, the picture for natural gas seems to be the following.

- Supply constraints exist, a function of age of producing fields and natural depletion and decline, the types of new reservoirs coming on stream, and constrained investment in the E&P sector (a result of both historical factors, including consolidation in the E&P segment, as well as more recent business turmoil among energy merchants).
- Demand destruction is a real and logical consequence of supply tightness and associated higher prices. Conservation and efficiency have important roles to play, but a considerable amount of demand destruction represents lost economic activity.
- Exogenous factors such as dynamics in the global oil market play a role.
- The current tight balance between supply and demand and resulting higher prices has been evolving for some time, but complacency hindered recognition of these dynamics.
- *If economic recovery takes hold and normal or near normal winter weather patterns remain in effect, and if oil prices remain firm, upward pressure on natural gas prices could exist for some time.*

ECONOMIC DEVELOPMENT CONSIDERATIONS OF HIGHER PRICES

As **Figure 10** below illustrates, the range of potential demand loss for natural gas is 0.7 to 7.0 billion cubic feet per day (bcf/d). A number of variables will dictate the ultimate outcome. This range is an indication of the economic consequences of natural gas prices. Shut-ins, shut-downs, and switching reflect decisions mainly by industrial users about their fuel supply mix given relative fuel prices. Conservation and weather related impacts represent a new dynamic – that of price induced adjustments among residential and small commercial customers. Based on anecdotal information from large utilities, these adjustments are expected to be permanent. Energy efficiency programs by industrial and large commercial users are also expected to be permanent. Should prices drop substantially as supply-demand interactions balance the market, demand recovery would create new pressures on supply. *Importantly, it is possible that a new market equilibrium will be reached far below previously expected levels of total annual consumption for the U.S., lending support to the conclusion that a 30 trillion cubic feet (tcf) market will be achieved only if it can be supplied at a reasonable cost and price.*

Figure 10. Extent of Demand Destruction (and Possible Recovery)

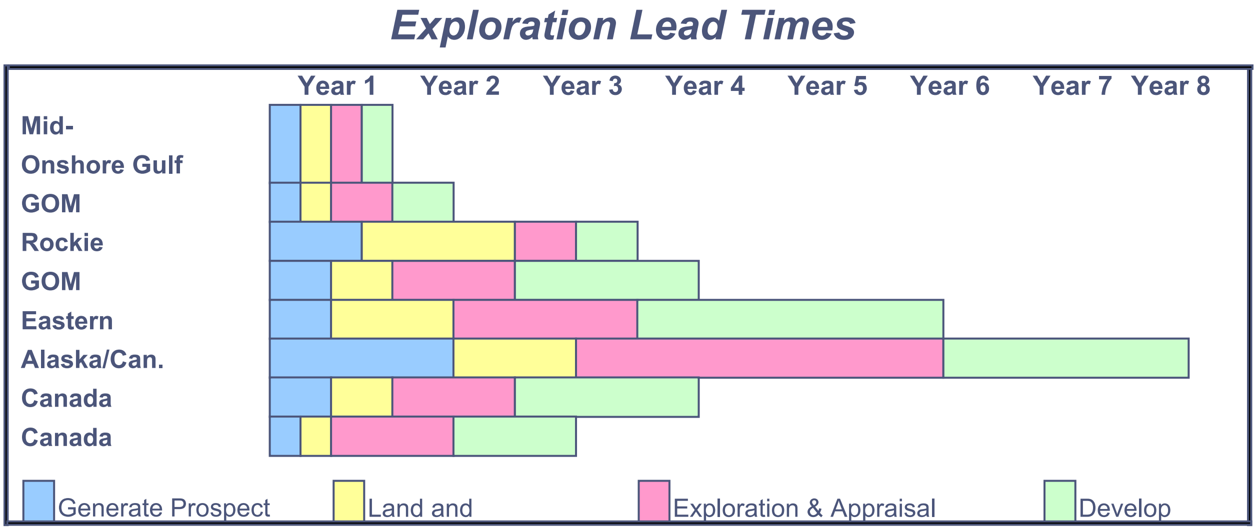


Source: Anadarko Petroleum Company

CONSIDERATIONS FOR THE DOMESTIC RESOURCE BASE

Important variables for the domestic resource base are capital availability and access to new reservoirs. With regard to capital outlays, E&P projects require lead times, some of which are lengthy (see **Figure 11** below). The E&P industry has responded to sharp price cycles and price volatility for oil and gas by consolidating, reducing costs (including new technology applications and improved asset management practices), and employing risk management. A common form of risk management is a "natural hedge" in which capital budgets are reduced when prices are not favorable for E&P investment and targeted returns. This means constant pressure on E&P projects to compete with other opportunities. These are long term trends that have been in place since the oil and natural gas market disruptions of the 1970s. A new, critical variable is the loss of capital provided by energy merchants.

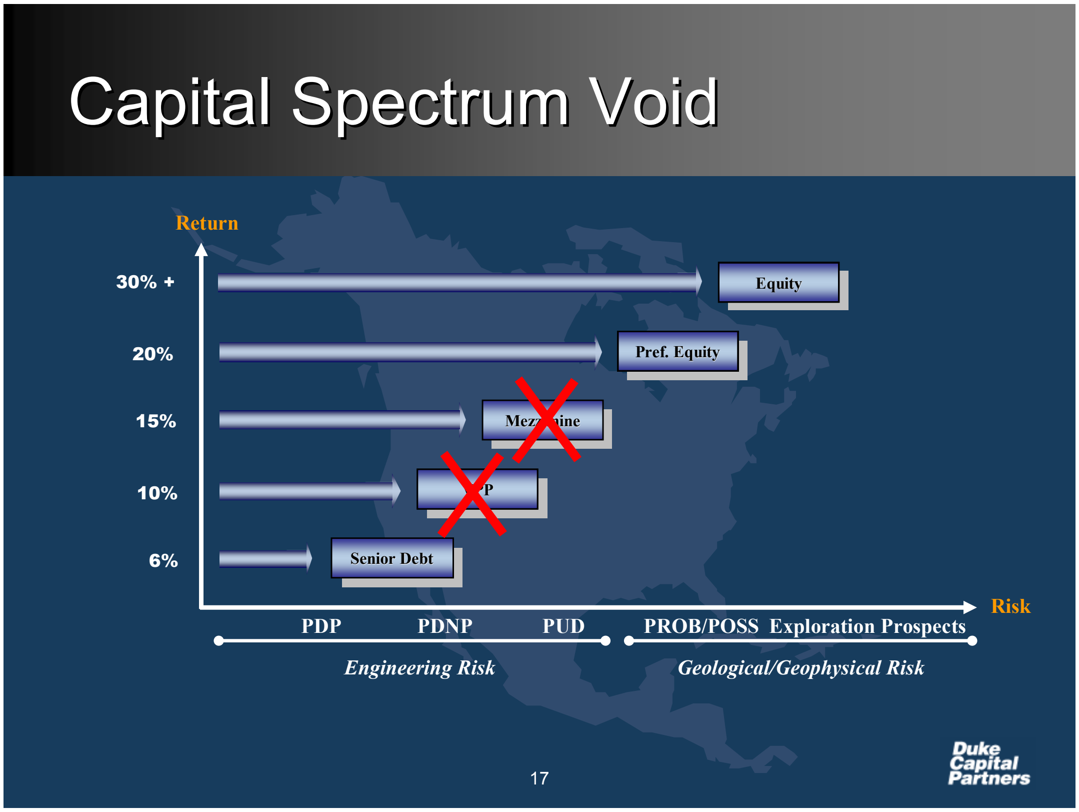
Figure 11. E&P Capital and Typical Lead Times



Source: Anadarko Petroleum Corp.

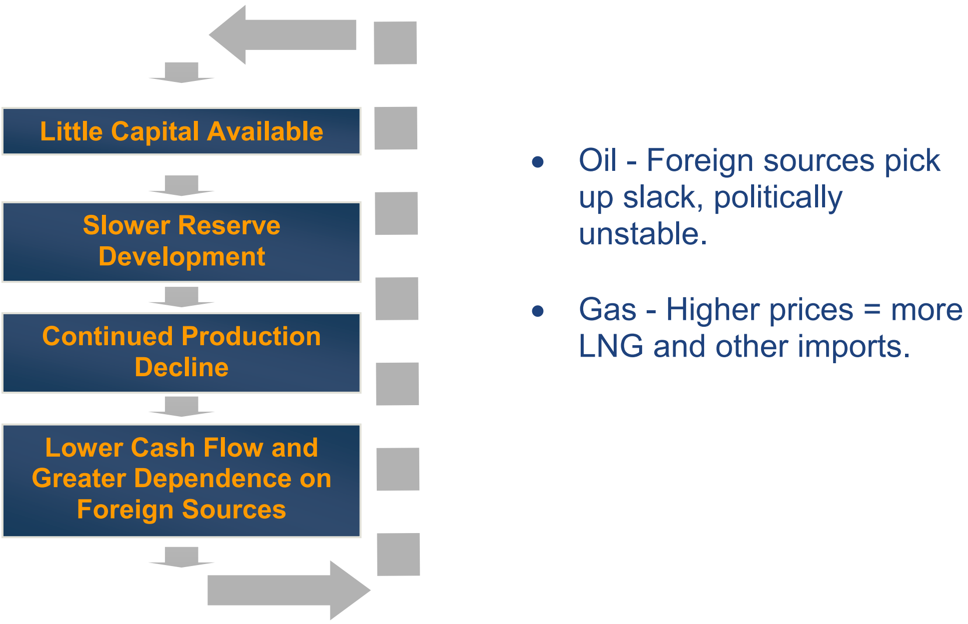
Energy merchants are the unregulated affiliates of pipelines and utilities that have been driving energy trading and risk management in the restructured U.S. (and Canadian) natural gas markets. Most of these enterprises established producer finance programs in order to diversify into upstream positions and to stimulate development of natural gas supplies in the U.S. Senior debt from commercial banks is most easily accessed for proved developed production (PDP). Producer finance played a key role for higher risk investments – proved developed but non-producing (PDNP), proved but undeveloped (PDP), to some extent, the highest risk category of probable and possible exploration projects. Capital expenditures by energy merchants for volumetric production payments (VPP) and mezzanine lending have been removed from the producer capital marketplace as energy merchants responded to post-Enron credit downgrades, lost liquidity for trading and risk management, and focused efforts to restore profitability, improve balance sheets, and achieve recovery in credit ratings and share valuations. Companies that have exited or reduced their presence in the producer finance marketplace include El Paso, Mirant (Southern Companies), Aquila (Utilicorp), Enron, of course, Shell (for reasons other than the energy merchant collapse), and Duke Energy Capital Partners (which provided the information in **Figure 12** and **Figure 13**). While private equity has stepped into the void, it is difficult for equity providers to leverage returns, limiting activity. One conclusion to be drawn is that with inadequate capital flows into E&P projects, the U.S. will face higher imports of both oil and natural gas (in the form of liquefied natural gas or LNG).

Figure 12. The State of Producer Finance



Source: Duke Capital Partners

Figure 13. Impact of Capital Constraints on U.S. Energy Supplies



Source: Duke Capital Partners

ROLE OF FEDERAL LANDS AND MANAGEMENT OF THOSE LANDS

Because the U.S. still relies heavily on onshore fields for our natural gas supplies, federal lands access and associated management issues are worth consideration. Significant problems exist with respect to data quality and availability associated with potential oil and gas leasing. The following case study illustrates a typical situation.

A Texas independent researches an area and determines it is a good place for new oil and gas leasing. He orders maps showing U.S. Forest Service lands administered by the Bureau of Land Management for oil and gas leasing. The maps do not show any restrictions for leasing. He determines that significant U.S. Forest Service acreage is prospective and nominates it for an upcoming oil and gas lease sale (oral auction).

During the next nine (9) months the acreage nominated for oil and gas leasing is reviewed by the U.S. Forest Service and all of the nominated acreage appears in an announcement for an upcoming sale.

The announcement comes out about six (6) weeks prior to the sale. On the lease announcement is mentioned several types of stipulations that would affect the development of oil and gas on the acreage. There is no indication of the significance of the stipulations (no maps, no geographic descriptions), but contact information is provided for the independent to make inquiry to the Forest Service regarding the degree to which development would be impacted by the restrictions.

The independent contacts the local forestry expert who describes the extent of a bird habitat that will affect 50-85 percent of the area. The "No Surface Occupancy" basically condemns the area for oil and gas leasing. The independent drops plans for the area and moves on to areas where minerals are in private hands.

The point of this story is that if the independent had been able to make an early assessment of the extent of "No Surface Occupancy" the acreage probably would have not been nominated in the first place, saving both the Forest Service-BLM and the independent time and money.

POLICY INITIATIVES FOR CONSIDERATION TO ENHANCE ONSHORE E&P

Tax Credits on Low Deliverability, Long Lived Unconventional Gas Resources/Reserves

- The maturity of the U.S. gas supply has been documented many places. Charts of decreasing well life and reserves per well are frequently shown. Most of this data deals with conventional gas supply that has been developed over the past 60-plus years since the construction of major interstate pipelines in the 1940's.

- Unconventional gas production from reservoirs such as coal seams (termed coalbed methane – CBM – or coal seam natural gas), shale gas, and tight gas sands has been developed later and until recently more slowly than conventional gas. The reason for this was the low deliverability from wells producing from these resources. Better technology, higher gas prices, and pipeline infrastructure caused some of these resources to be developed such as tight gas sands in the San Juan Basin in the 1950's.

- However it was not until the late 70's and especially the late 80's to early 90's timeframe when new basins and new resources began to be developed. This was a time of relatively low gas prices (certainly compared to today), and the availability of tax credits associated with production caused new sources of capital to come into the industry to speed development of these resources and prove up technologies. Examples are the Antrim Shale in Michigan, CBM in the Black Warrior Basin and San Juan Basins, and tight gas sands in the Rocky Mountains, especially in the Piceance and Denver-Julesburg Basins. Over the decade of the 90's over 25 trillion cubic feet of gas in long lived, proved reserves were developed. Over that time frame gas unconventional gas production increase from near nil to almost 10 percent of U.S. production today – and the percentage is increasing.

- While it is true that tax credits may not be as critical to the development of these resources in times of high gas prices, other factors are worth consideration.

    - First, not all of the country's producing areas have experienced high wellhead prices over the past year. Basis differentials between Henry Hub and the Rocky Mountains resulted in wellhead prices of less than $1.00/mcf in the Rockies. At this price it is uneconomic to drill new wells and in some cases produce from existing ones. Gas prices are high now, but just a little over two (2) years ago the Henry Hub price was below $2.00/mcf.

    - Second, while conventional wells produce at maximum rate on the first day, unconventional wells typically do not reach peak production for months or years. This dampens rates of returns associated with unconventional reserve development making it a less attractive investment. Tax credits have historically helped the discounted cash flow economics on unconventional gas to make this resource attractive enough for investment to go forward. In fact, during times of high gas prices the industry, fearing that high prices will not be sustained, is actually reluctant to invest in unconventional gas and favor the higher returns associated with conventional gas.

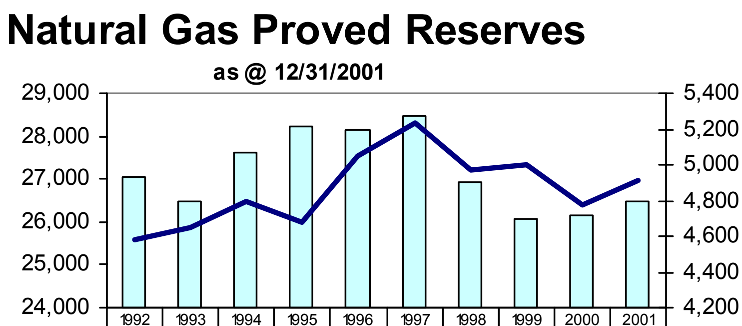
    - Third, some of the best unconventional gas resource basins have been discovered and are on production. The risk associated with finding new ones is considerable. Attracting capital to defray the risks is a key to adding new reserves. There is a significant step-up in risk associated with developing new basins and new reserves.

Tax credits which played an important role in the late 80's and early 90's could play a similar role again, done carefully and with attention to environmental protections.

ROLE OF OFFSHORE RESOURCES IN PARTICULAR
AND MANAGEMENT OF THOSE RESOURCES

With respect to offshore natural gas resources, it is clear that the Gulf of Mexico remains a rich province, and that deep water exploration in particular offers good prospects for development. **Figure 14**,
Figure 15, and **Figure 16** below shows the role of the U.S. GOM with respect to proved reserves and production in established areas, as well as the emerging role of deep water blocks. A critical issue for GOM supply deliverability is transportation, including new technologies (like compressed natural gas transport) to move gas from production location to onshore markets.

Figure 14. U.S. Gulf of Mexico Proved Reserves

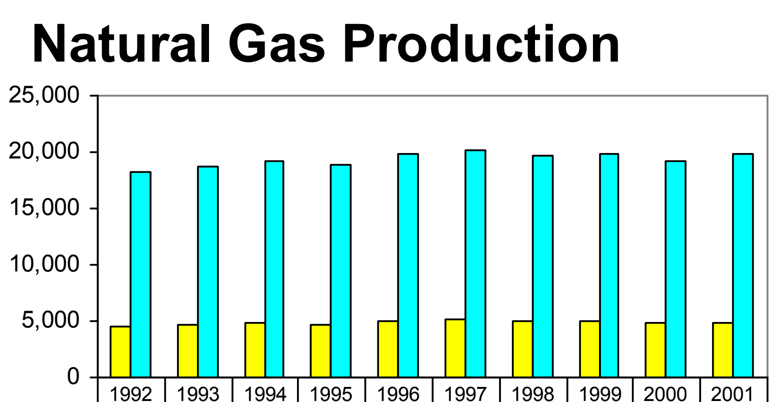


	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
GOM Gas Reserves, bcf	27,050	26,463	27,626	28,229	28,153	28,455	26,937	26,062	26,172	26496
GOM Gas Production, bcf	4,576	4,651	4,797	4,679	5,045	5,230	4,967	5,000	4,773	4913

Source: EIA

U.S. gas reserves increased 3% over 2000. 24% of the U.S. total discoveries in 2001 were in the GOM.

Figure 15. U.S. GOM Production

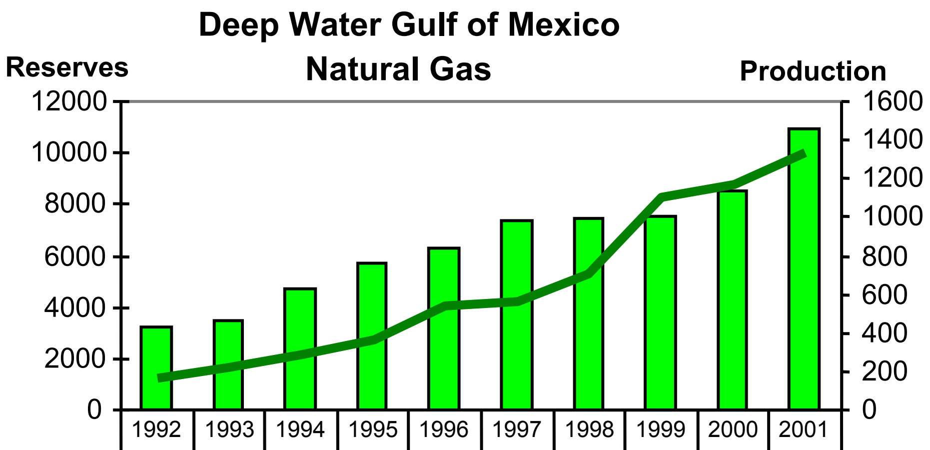


	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
GOM Gas Production, bcf	4,576	4,651	4,797	4,679	5,045	5,230	4,967	5,000	4,773	4913
U.S. Gas Production, bcf	18,269	18,641	19,210	18,874	19,783	20,134	19,622	19,856	19,219	19,779

GOM produced 25% of U.S. dry gas in 2001.

Source: EIA

Figure 16. U.S. GOM Deep Water Potential

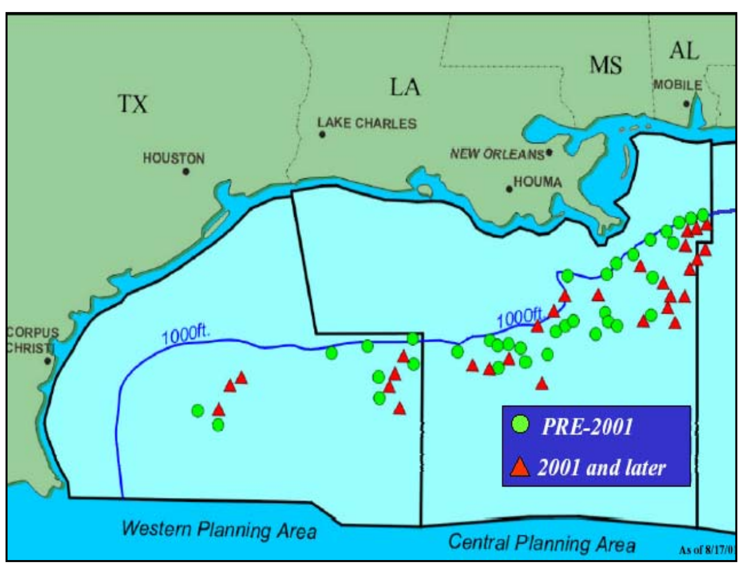


	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
Gas Reserves, bcf	3225	3438	4709	5751	6322	7343	7425	7533	8506	10943
Gas Production, bcf	162	224	288	361	544	565	711	1099	1165	1334

Source: U.S. EIA

The deep water areas represent considerably higher risks and new demands on technology and logistics. In spite of these constraints, the industry has achieved success and is now better able to move toward a lower cost structure for deep water exploitation.

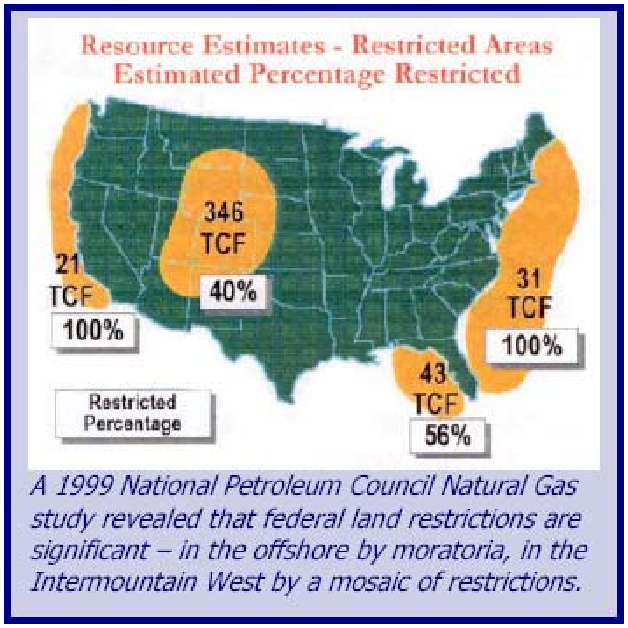
Figure 17. Recent Successes in the U.S. GOM



Source: U.S. Minerals Management Service

Success achieved thus far for the GOM deep water, and the ability for the industry to maintain operations in this demanding province overall, indicate that areas currently blocked to access by moratoria deserve a second look. **Figure 18** represents the most recent estimate of natural gas reserves that could be accessed both onshore and offshore with appropriate policy mechanisms, including environmental safety and protections.

Figure 18. Implications of Offshore Moratoria



Courtesy of Independent Petroleum Association of America

ROLE OF LNG

With constraints on capital and limits to access for drilling, LNG is a actively discussed option to meet U.S. natural gas supply requirements. Currently, LNG comprises only about one percent of U.S. natural gas consumption (**Figure 19**). The U.S. has a diversified supply base for LNG (see **Figure 20** below). Of interest is that our LNG imports roughly offset natural gas exported to Mexico via pipeline.

Figure 19. Distribution of U.S. Gas Supplies

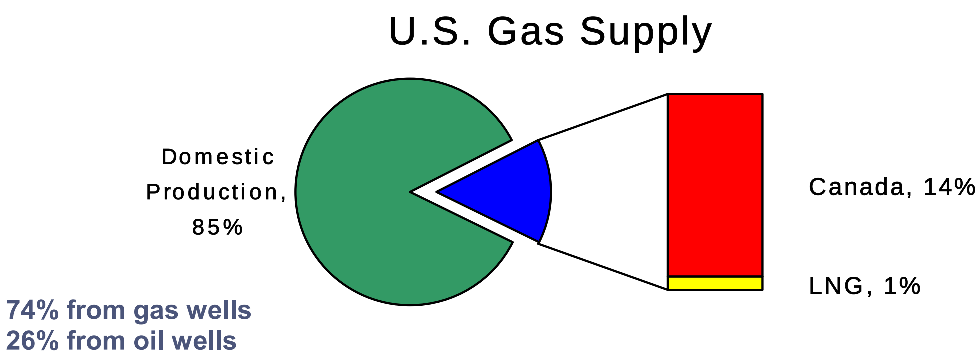
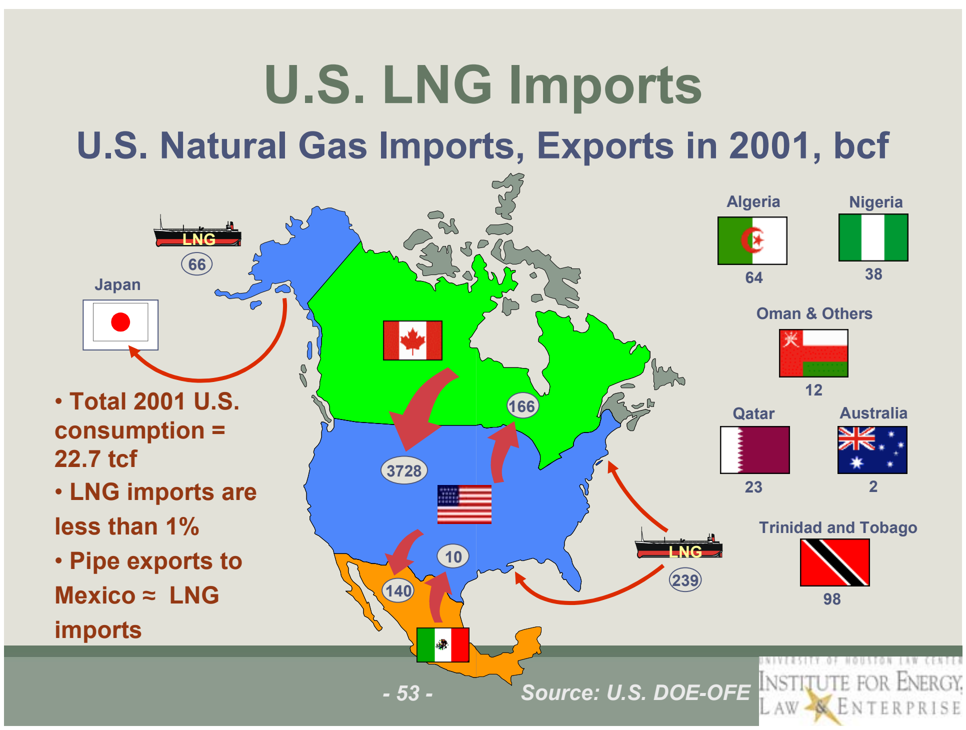
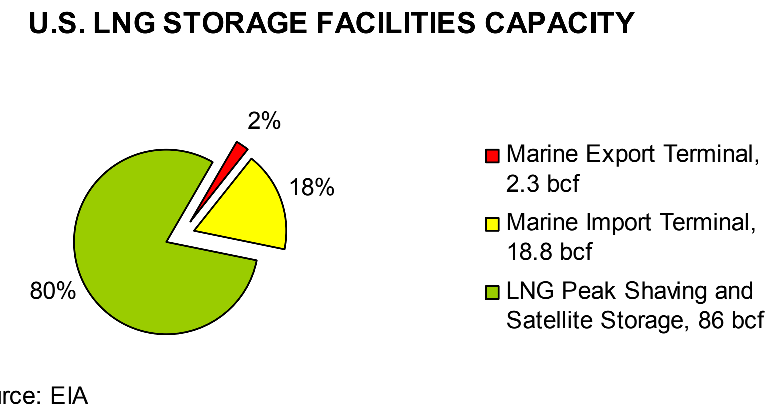


Figure 20. U.S. LMG Supply Sources



The U.S. also has the largest number of LNG facilities in the world, since much of the LNG we import is used for peak-shaving by utilitites.

Figure 21. U.S. LNG Storage Facilities



A number of new marine import terminals have been proposed to supplement our existing 19 bcf of capacity. Two essential questions for LNG are whether additional natural gas imports can enter the U.S. market on a cost and price competitive basis, and whether new LNG import facilities can be developed safely.

Figure 22. Existing and Proposed Import Terminals

On the question of cost and price, the LNG value chain represents substantial cost and risk to the industry. However, the costs estimates shown in **Figure 23** are considerably less than when the LNG industry was launched roughly 40 years ago. Substantial savings have been achieved for both liquefaction and shipbuilding, and, importantly, the life spans of LNG tankers have been extended. The LNG value chain today encompasses significant technology improvements for both cost reductions and safety and environmental enhancements and protections.

Figure 23. The Current LNG Value Chain

EXPLORATION & PRODUCTION	LIQUEFACTION	SHIPPING	REGASIFICATI ON & STORAGE
$0.5-$1.0/MMBtu	$0.8-$1.20/MMBtu	$0.4-$1.0/MMBtu	$0.3-$0.5/MMBtu

The result of cost reductions across the LNG value chain is that, by U.S. Department of Energy estimates and based on industry reports, LNG cargos can enter the U.S. when Henry Hub prices are roughly $3.00 and provide sufficient returns on investment to support expansion of the industry. Indeed, LNG cargos were entering the U.S. market when Henry Hub prices were roughly $2.50, an indication of the tremendous progress made by the industry to manage its cost structure and build commercial expertise.

Figure 24. Natural Gas Prices, $/mmBtu (U.S. DOE – OFE)

	1998	**1999**	**2000**	**2001**
Canada	**$1.91**	**$2.18**	**$3.90**	**$4.36**
LNG Imports*	**$2.31 – $2.84**	**$2.15 – $2.69**	**$2.73 – $3.93**	**$3.29 – $5.00**
Domestic/Henry Hub**	**$2.08**	**$2.27**	**$4.32**	**$3.98**

* Includes both landed and tailgate prices; lower price is generally landed price
** Mean, daily spot prices

Regulations are designed to prevent incidents at LNG facilities from occurring and if they do occur, from human or other error, to protect the public from any impact. Generally, the commercial framework for LNG includes the following principles.

- *Contain the product.* This includes metallurgy for storage tanks; facilities design such as double hulled ships, the option to use full containment construction for land-based storage tanks, and so on.

- *Prevent effects.* This second layer of protections is designed to minimize spills and entails the deployment of gas detection systems, shut off valve systems and the like.
- *Secondary containment.* The third layer of protection applies to both ships and storage tanks (for example, dikes and berms surrounding tanks that can contain more than 100 percent of the product), with the objective of capturing product should a breach occur.
- *Separation distances.* Appropriate setbacks, operating distances for tankers, and overall siting requirements ensure protection for public areas that might be near LNG facilities. Dispersion models, thermal radiation zones, and other requirements are used to establish separation distances.

A comprehensive review of data and information reveals that:

- The LNG industry is not without incidents but it has maintained an enviable safety record over the last 40 years. Technological advances and regulatory oversight will ensure maintenance of that safety record going forward.
- The industry has continued to develop advanced technology and control systems to ensure safety and reliability.
- The experience of the LNG industry demonstrates that normal operating hazards are manageable, certainly so relative to other public risks and hazards.

Other critical considerations for LNG include the following.

- *Public education is essential.* An LNG consortium has been developed at the University of Houston to assist in this effort. The consortium includes industry, government, peer expertise in engineering and safety design, and outside peer review for environment and safety considerations. An overview briefing paper is currently available, and a definitive briefing paper on safety should be in public distribution by mid-summer 2003. For information on the consortium, go to www.energy.uh.edu, LNG page.
- *As the U.S. expands our imports of natural gas, our relationships with producing countries will become even more critical.* The development of natural gas worldwide is not only beneficial to consuming countries, but also to producing ones. Development of LNG will help to reduce flaring. The LNG value chain will stimulate additional E&P investment for natural gas worldwide, and help to support development of domestic markets for natural gas, including gas-fired power generation, in producing and exporting countries. *Training, education, and skills development in the international arena are essential to ensure safe, wise, and transparent development and utilization of the global natural gas resource base.*

CONCLUSIONS

The natural gas industry and its customers are experiencing the price effects of a tight supply-demand balance. Our domestic resource base should be the first priority – it is our largest supply pool. LNG and other alternatives can be used to supplement our domestic base, and help to moderate high prices. Free and transparent markets, rational responses in conservation and efficient use, clear and timely data and information, access to locations for drilling, and safe development of LNG facilities can help to ensure our natural gas future.